BEFORE THE STATE OF WASHINGTON
ENERGY FACILITY SITE EVALUATION COUNCIL

IN RE APPLICATION NO. 99-1 SUMAS ENERGY 2 GENERATION FACILITY	EXHIBIT_____(RE-T)

COUNSEL FOR THE ENVIRONMENT'S PREFILED DIRECT TESTIMONY

WITNESS #__: RONALD EACHUS

Q. Please state your name and business address

A. My name is Ron Eachus. My business address is 940 Salem Heights Ave. S, Salem, Oregon 97302.

Q. Please summarize the scope of your testimony.

A. First I will provide an overview of my background and experience relevant to Northwest energy issues. Then I will describe some changes in the Northwest energy situation since the prior round of testimony last summer and their implications for consideration of the Sumas Energy 2 proposal.

Q. What is your background and experience?

A. In May of this year I completed nearly 14 years of service as a Public Utility Commissioner for the State of Oregon. For eight of those years, including the last 3 years and 8 months, I was chairman of the three-person Commission. I was appointed in October of 1987

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and was subsequently reappointed three times, serving until the end of my most recent term, which expired in May 2001. This tenure spanned a period of major changes in the electric utility industry and the way in which it is regulated. Since leaving the Public Utility Commission, I have served as a consultant for the National Regulatory Research Institute and the National Association of Regulatory Utility Commissioners on two information and communications technology assessments in the countries of Georgia and Russia. In this capacity I served as the regulatory expert on two four-person teams sponsored by the United States Agency for International Development. My resume is attached as RE-1.

Q. During your time with the Commission, did you see an evolution from the traditional vertically integrated utility system to independent generation of power and more competitive wholesale markets?

A. Yes, the industry changed dramatically during my time on the Commission and is the basis for the opinions I currently hold on the energy market and the appropriate regulatory strategies to protect citizens while we develop working competitive markets for generation.

Q. Please then provide a general summary of the changes in the electricity industry during your tenure on the Oregon Commission?

Evolution of the IRP.

A. When I became a Commissioner the electric industry was composed of the traditional vertically integrated utilities that supplied and bundled the generation transmission, and distribution functions into their rates and services. The focus of the Commission at the time was on resource planning. In 1989 the Oregon Commission established a least-cost, or integrated resource planning (IRP) process. In this process the utilities were required to submit resource plans every two years that considered the costs of all resource options over both the short and the long term. Included in those costs were certain external costs related to each specific resource

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option. The objective was to conduct a public process to identify one or more resource plans that we considered “optimal.” By that we meant resource acquisition strategies that would meet the utility obligation to serve with the greatest efficiency and the lowest cost. We considered external costs, which were mostly environmental, to reduce the overall cost to society and to reduce the risk to ratepayers that those costs would be greater if internalized at a later date. Another purpose was to conduct a public review of the plans before a utility made an investment rather than the previous pattern of making an investment and then reviewing the decision at the time the utility asked the ratepayers to cover the costs. This was to reduce the level of conflict in rate cases and to reduce the utility’s risk of disallowance of part of its investment.

The early IRP’s focused on delaying investment in new generation through cost-effective energy efficiency. We also realized though that without changes in the method of regulation, the utility incentive was to build power generation and to sell kilowatt hours rather than to help customers save energy. That spurred development of new rate-setting methodologies to encourage the utilities to invest in energy efficiency for their customers.

Energy Policy Act

The landscape changed in the early part of the 1990’s. The Energy Policy Act of 1992 and subsequent Federal Energy Regulatory Commission decisions opened the generation market to new generators and new marketers. The utilities still had a monopoly on distribution and transmission, but not on generation. In addition to energy efficiency, purchasing power from other utilities and independent power generators in what was at the time a surplus market became a viable alternative to a utility building its own generation. New markets for the trading of electricity were developing. The process of greater reliance on the market was accelerated in Oregon in 1993 when Portland General Electric’s Trojan nuclear plant was shut down. PGE then had to enter the market to purchase half of its power supply and essentially became a power trader.

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Changing Rate Setting Structure

The changing nature of the market changed the nature of the least-cost plans and the way we regulated the utilities in Oregon. Through much of the last half of the decade of the 1990's we enjoyed a surplus of power while the markets were going through their transition. During this time most of the new generation that was being added was undertaken by independent power producers, some of which were unregulated affiliates of utilities. Nearly all of the new generation was based on natural gas. As a consequence of these developments, the Oregon PUC had to adapt its rate-setting methodologies to reflect greater levels of supply coming from power purchases and a greater exposure to costs of natural gas over which utilities had little control. The least-cost plans took on a different nature with greater focus on power purchase options and a shortening of the planning horizon. The Commission also adopted different rate-setting methods including periodic purchased power cost adjustments and various forms of performance based approaches, including both price caps and revenue caps. We also began analyzing utility costs in a different manner to begin the process of functional unbundling. In addition the new market meant there were many new entities affected by regulatory policies and the number of participants and the diversity of interests in our proceedings increased.

Electric Industry Restructuring

The increased competition in the generation and marketing of electricity led to the desire on the part of some customers to rethink the industry structure in Oregon. It provided opportunities to buy supply from entities other than the monopoly utilities. In the last five years I've been the lead Commissioner in development of Oregon's electric industry restructuring law. The law was designed to reflect and to accommodate the changes in the fundamental nature of the electricity market while protecting customers at the same time. Discussions about statutory changes began in the 1997 Oregon Legislature and in 1999 a restructuring law passed giving larger customers the right to buy supply from an entity other than the utility. The Oregon PUC was given the responsibility of developing rules. Prompted by the California energy crisis, the

2001 Oregon Legislature made some minor changes and delayed implementation of the customer choice options from October 1, 2001 to March 1, 2002. Under this law the utility functions and rates are unbundled and large customers are allowed to choose a supplier other than the utility. Smaller customers are given a portfolio of options, which includes a traditional cost-of-service based rate and a market-based rate.

In summary, in the fourteen years I was a Commission, the industry has gone from monopoly utilities that built generation and bundled rates to a competitive market for supply, an unbundling of utility rates and functions, and increased customer choice. The market for electricity has fundamentally changed. There are new markets and new players in the market and the utilities have had to evolve from simply generators of power to market traders. It is a much more dynamic, complicated and uncertain world than when I started. While the Oregon PUC may have adopted specific responses to industry changes different from those of other Commissions, the range of issues and the impact industry structural changes had on the regulatory environment in Oregon is similar to that faced by most utility regulatory bodies throughout the Northwest region and the United States.

Q. What were your basic responsibilities as a Commissioner?

A. The responsibilities are generally outlined in the statutes. My job was to assure that rates were just and reasonable, to protect and represent the ratepayers of the investor owned utilities and to protect the public generally. I addition I had a legal responsibility to make sure the regulated utilities provided reliable and adequate service which includes providing the utility with a rate of return on investment sufficient to attract capital. This is the typical legal framework for state utility regulatory commissions in the United States and elsewhere.

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Q. How did you generally view your role as a Commissioner?

A. Within the context of the statutory obligations, I have always viewed regulation as more of an art than a science. In essence, I had two roles. One related to process and one related to the making of a decision. I had a responsibility to make sure that all parties had ample opportunity to make their case before the Commission and to provide means of dispute resolution when necessary. As a decision-maker, my role was basically to weigh the various positions of the parties involved in our formal and informal proceedings, to consider the options and to evaluate the consequences of particular actions to determine what I believed was or was not in the public interest. Such decisions are not always very clear cut. It takes a balancing of the private interests and the public impact over both the short and the long term. But in essence, my role was to make sure that in debates over law and policy, the public's larger interest was considered and served.

Q. Have you read Mr. Litchfield's testimony and do you have any comments on it?

A. Yes, I have. Mr. Litchfield attempts to describe events that occurred in the California, Northwest and Western electricity markets since last August. However, the emphasis is on the past events, presumably to reinforce the applicants stated claim in its revised application that without more power generating capacity in the near term, similar events will be inevitable in the future, therefore there is a need for the Sumas Energy 2 facility and it should be built.

Q. Do you agree with Mr. Litchfield's assessment?

A. No, I do not agree with any conclusion that the events of the past year will repeat themselves unless SE2 is built. The logic of the applicant's case seems to be that the problems of the past year were caused by inadequate supplies. Therefore more supply is needed. Further, if SE2 isn't able to provide new supply, then we are doomed to repeat the events of the past year. The events of the past year are instructive but there was more underlying the difficulties in the market and the run-up of prices than simply inadequate supply. And while it is true that tight

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supplies can be catalysts for events like those of last year, there are strong indications that the future is not as bleak as the past has been. Those past events have led to changes in the future that will help enable the industry to reduce the likelihood of outages and the extreme price volatility caused by shortages of supply. Specific examples are:

1. Many utilities are raising rates to reflect the increases in their wholesale power cost. While it is hard to predict the magnitude or duration of the rate increases, it is safe to assume that they will induce some reduced consumption.

2. Along with the price increases, utilities are adopting new rate designs that encourage customers to change usage patterns and reduce consumption during the peak hours when supply costs the most. While the recent price increases may be temporary or may fluctuate with the market, the rate designs based on real-time usage are likely to be a more permanent part of utility rate structures.

3. To get through this period of high prices and potential shortages many utilities adopted programs for voluntary load curtailment. These programs contributed to the region's ability to avoid shortages and reduced the demand for costly supplies during peak hours. Again, these are likely to continue as more permanent elements of utility tariffs in the future.

4. There are significant amounts of new supply planned in the Northwest for the near future. The amount of new generation being considered for approval by facility siting agencies in Oregon and Washington exceeds the amount and the pace of new generation forecast in the Northwest Power Planning Council March 2000 study on "Northwest Power Supply Adequacy/Reliability Study Phase 1 Report," that was often sited in previous testimony on SE2. (see Exhibit 42.2).

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Q. Can you provide the Council with some examples of the recent rate increases and the implications of those increases?

A. I have not surveyed all the rates of the utilities in the Northwest but I am familiar with some changes. In general, rates are going up to reflect the increased costs of the market. Those who generate their own power with natural gas have been affected by high natural gas prices. Where power is purchased from the supply market, costs of purchased power has significantly increased due to increased natural gas costs and reduced surpluses. In general rate increases are double digit and some are very significant. Some utilities have started with one double-digit increase and then followed later with another one.

The Oregon Public Utility Commission recently granted PGE a rate increase of an average of approximately 35 percent. Residential rates are expected to go up about 26 percent and industrial rates will increase 47 percent. As pointed out in other testimony, BPA is increasing its wholesale rates 46 percent. That, in turn is prompting its publicly owned utility customers to raise rates October 1 when the BPA rates take effect. After raising rates 5.4 percent in April, the Eugene Water and Electric Board is proposing an increase of 36 percent for residential customers and between 32 to 38 percent for commercial and industrial customers. The Emerald People's Utility District raised rates 16 percent in April and will raise rates another 16 percent in October. The Springfield Utility District raised rates by 16 percent in April and will raise them another 16 percent October 1.

The Washington Utility and Transportation Commission recently granted Avista a 25 percent rate surcharge, subject to refund, through the end of next year. Puget Sound Energy has requested a 17 percent increase to be effective Nov. 1 to reflect increased power costs. That increase, however, is being contested. Seattle City Light has adopted four different surcharges in the last year, raising rates 55 percent. Tacoma Power adopted a surcharge increase of 43 percent for residential earlier this year and will be continuing the surcharge at 33 percent October. Clark

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County raised its rates by an average of 23 percent in January, followed by a 20 percent increase in August.

Mr. Litchfield points out that one of the difficulties during much of the past year was that while there was upward pressure on wholesale prices and extreme price volatility, the retail rates for many utilities did not reflect those increased costs and did not encourage customers to appropriately respond with changes in demand.

However, in considering the future supply picture one should not assume that the pattern of the past will be repeated. Utilities did raise their prices within the past year and many are raising them again in October. The rate increases have already affected demand. The price increases will induce a reduction in demand, either through simply reducing usage or through changing the timing of the use, or both. While it is true that power costs may go back down and rate increases may only be temporary there will be a residual effect. The price increases are at a level the Northwest hasn't seen for a long time. The increased costs have increased the cost-effectiveness of energy efficiency measures and many utilities are ramping up their efforts to offer those measures to customers. If the price does goes back down, there may be some take back, but it is unlikely that all the efficiency gains will be lost. In addition, the investor owned utilities in the Northwest are operating under some form of purchased power cost adjustment mechanisms which will lead to more frequent adjustments in the power cost component of rates. This will reduce the lag time between the incursion of wholesale costs and their reflection in rates. Furthermore, many utilities are changing their rate designs to more accurately reflect the costs of using more power or using it at different times of the day.

Q. Can you describe some of these new rate designs and their implications for power supply?

A. I haven't gone through all the rates and rate designs of all the utilities in the Northwest but I do have some examples. Puget Sound Energy (PSE) has asked the Washington Utility and

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Transportation Commission to continue its time-of-day pricing trial through May of 2002. The utility has had about 300,000 customers on the time-of-day rate in which they pay about 30% less during the low demand off-peak hours than during the high demand on-peak hours. The company also has a block of customers who are receiving detailed personal reports about on the timing of their energy consumption, but those customers do not receive time-of-day rates. PSE compared the usage of customers receiving the time-of-day rates with those who received information about the timing of their energy consumption but did not receive any price signals encouraging changes in usage patterns. According to the PSE press release on the application for extension of the tariff, compared with the customers receiving the detailed information about the time of their usage but no price signals based on the time of consumption, "Customers paying time-of-day rates shifted about 5 percent of their electricity usage, on average, from the morning and evening hours when public demand for power – and wholesale power prices – are highest." (RE-2).

Q. Have other utilities changed their rate structure to address demand?

A. Yes, there is a growing list of utilities who have changed their rate structures. In Oregon both Portland General Electric and Pacific Power and Light are changing their rates and their rate structures. The structural changes reflect both the requirements of the state electric restructuring law enacted in 1999 and revised in 2001 and the desire to send better price signals to residential customers. In its recent rate case PacifiCorp (PP&L) received approval for a cost-of-service inverted block rate design. The first block is 500kWh and below. The second block is between 500 and 1000kWh. The third block is over 1000kWh. The rates are to be set so that there is a 20 percent price differential between the first and third blocks. Other utilities, such as PSE, either have or are introducing similar inverted rate structures. The Eugene Water and Electric Board will be implementing a three-tiered rate structure in which the rate for the last block of use will be nearly double that of the first block. The effect of this type of rate structure is to encourage customers to use less energy.

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Under the Oregon law, the investor owned utilities are also required to offer a “market based” rate as well as a cost-based rate as part of a required portfolio of options to residential and small commercial customers. Consistent with Oregon Public Utility Commission adopted policy for the portfolio, PacifiCorp will be offering a time-of-day option to customers with rates based differentiated by on-peak, mid-peak, and off-peak times. Customers will have choice between the cost-based inverted rate structure in which the price is higher with increased usage or the market-based rate in which price is highest during on-peak usage. Initially, the time-of-day rate offering will be limited in both participation and impact. It will be limited to 3500 accounts because it requires new meters and the company is concerned that it may have to invest millions of dollars in time-of-use meters without knowing whether or not it is cost-effective. The offering also contains a guarantee that a consumer’s energy charge will not be more than 10 percent higher than it would have been under the standard cost-of-service rate. The OPUC adopted a policy of providing such a guarantee in at least the first year of the time-of-day rate offering in order to encourage participation.

PGE has also gone to an inverted rate structure in which usage over 225kWh costs nearly 25 percent more than the first 225kWh. Under the Oregon rules, PGE will also be offering a time-of-use rate using the same basic structure. Again, as with PacifiCorp, there are some initial limitations on the individual customer impact of the time-of-use rate.

Neither PGE or PacifiCorp have filed those time-of-use rates yet and they will vary according to the different cost structures of each company, but according to the model adopted by the Oregon PUC, the rate for on-peak could be nearly three times higher than the rate for off-peak demand. Customers who sign up for the option must do so for a 12-month period.

Despite these limitations, the rate designs of both PGE and PP&L, whether cost-of-service or time-of-use, encourage customers to use less and to use it during off-peak times.

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Q. Are these rate designs new to the Northwest and are they likely to be permanent?

A. During past periods when rates were being increased because utilities were adding their own new generation to rate base, some utilities applied inverted rate structures. The time-of-use rate design has been used in other parts of the country but it is not common in the Northwest because we have traditionally had little difference between the costs for off-peak and on-peak power. This situation has changed with a greater reliance on purchase of non-utility generation to serve load and with the development of an hourly spot market which can have significant levels of price volatility. Since a small reduction in peak demand can generate a much larger reduction in costs, I believe we will see a continued emphasis on rate design to give customers a more accurate reflection of the costs their usage imposes on the system.

Q. What conclusions have you reached based on these rate changes.

A. The industry, and those who regulate it, are overcoming the shortcomings the disconnect between wholesale costs and retail rates caused last year. Rates now reflect those higher costs, regulators and utilities are reducing the lag time between incursion of costs and inclusion of those costs in rates, and customers are being sent price incentives to reduce usage during the high cost hours. These rates and rate designs will help contribute to reducing price volatility in the future.

Q. Please explain how the voluntary curtailment programs operate and whether in your opinion, they will they also contribute to reduced volatility in the future?

A. In response to the extreme prices of the past year, many utilities and BPA introduced voluntary curtailment programs to reduce load and avoid extreme costs or power shortages. These programs are also often referred to as demand exchange or demand buy-back. The specific provisions and methodology of each utility's tariffs vary but the basics are the same. Essentially the utility is offering to pay the customer to reduce load at a price that is less than what it would

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cost the utility to acquire power to serve that load. Typically that is during peak load periods when the market costs are highest.

The customer then has the option of deciding whether or not, given its operational constraints, it is better off operating and incurring costs for electricity usage or shutting down operations and being paid by the utility for the unused load. It is voluntary so it is an agreement of mutual benefit.

In Oregon both PGE and PP&L have voluntary curtailment tariffs. The Pacificorp tariff applies only to customers of 1MW or more per month. It operates like an auction in which the company lets the price it is offering be known and then the customers can pledge reductions. According to PacifiCorp the tariff resulted in the reduction of 74,000MWhr since it was put in place in December. PGE began its demand buy-back program earlier in July 2000. In its program, the utility declares an "event" during periods of high priced peaks and establishes the price it will pay eligible customers to reduce load. Since July the utility has declared 122 events. Since then the company says the tariff has resulted in a total of 279,000,000kwhrs of reduced load. Most of the reductions, 241,000,000kwhrs came during last winter. Initially it applied only to customers using 1MW per month or more, eight customers. However, the company has revised the tariff down to customers with 250kw per month, which includes another 25 customers.

In Washington, Puget Sound Energy, Avista and PacifiCorp all put voluntary curtailment programs in place last December. According to a March 8, 2001, staff report to the WUTC, three customers participated in the Avista program in December with a total of 613MWh curtailed. PacifiCorp had one customer participate, curtailing 3800MWhr. The three utilities reported that customers continued to be interested in the programs and all filed to extend the programs. Recently updated information from the WUTC documents additional use of the tariffs since December. According to WUTC staff compiled data, since the voluntary curtailment tariffs were adopted, PSE has had 80MWhrs curtailed, Avista has had 5628MWhrs curtailed and PacifiCorp has had 6934MWhrs curtailed. (RE-3)

Q. What conclusions can be drawn from the advent of these voluntary curtailment programs.

A. Utilities indicate they are planning on continuing to offer these tariffs in the future. They are consistent with recommendations in both FERC and NWPPC studies for mechanisms that enable customers to voluntarily participate in increasing reliability and reducing price volatility. When prices are lower and less volatile, the tariffs will not be utilized as much, if at all. But when prices are higher and more volatile, these tariffs not only provide mutual benefit to the utility and the eligible customers, they provide benefit to the market and other customers as well. They are a consequence of tight supply, but voluntary load reduction tariffs of the type adopted by the utilities above are a policy choice that will be an integral part of a competitive market and a hedge against extreme prices or inadequate supply in the future.

Q. Are there other changes in the conditions of the past year the Council should consider?

A. Yes. The company and Mr. Litchfield continue to imply that the Sumas Energy 2 facility is necessary to avoid the events of the past year. However, that approach gives little acknowledgement of how some of the underlying factors that led to the consequences of the past year are changing.

Q. What factors in your opinion contributed to the energy situation last year and are they likely to change.

A. One factor was the rapid increase in natural gas prices. Those prices have already gone down and have stabilized. Additionally, most new generation is coming from natural gas, so a general increase in natural gas prices will have an effect across the board. Another factor was the drought, which severely limited hydro capabilities. The past year the Northwest has been the second worst water year in the 71 years BPA has been keeping records. In other words this past year we have been near the bottom of the hydro curve. It strained the system but it should not be taken as a constant. The hydro supply can fluctuate significantly. As Mr. Watson pointed out in his first round pre-filed testimony (Exhibit 42) the worst water year on record is 4000 average megawatts less that the average water year and 8000 average megawatts less than maximum water conditions.

Another major factor was the problem in California where a flawed market design combined with tight supplies fostered excessively high prices and subsequent collateral damage in the Northwest market. The market design flaws are being addressed by FERC intervention. Plus, the supply situation in California has significantly improved. A California Energy Commission draft report has concluded that the outlook for the summer, the state's peak demand period, through 2004 is optimistic. As a result of additional energy efficiency and new generation, the draft report expects the statewide planning reserves are expected to range from 15 percent to 32 percent, which it says should be sufficient to maintain the seven percent operating reserve needed to ensure reliable service. Finally, the events of the past year have stimulated significant amounts of potential new generation to address the supply issues in the region and the West. The draft report is available at "http://www.energy.ca.gov/reports/2001-09-07_200-01-002_STAFF.PDF." The summary is attached. (RE-4)

Q. What are the implications of the changes in these underlying factors?

A. The implications of changes in some of the underlying causes of the extremes of the past year is that the events shouldn't be used as an assumption of what will happen in the future if any one plant is or is not built.

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Q. What is the Northwest outlook for increased power supply?

A. There are significant amounts of new generation being planned for the future in the Northwest. In Oregon there is currently 1440 MW under construction. (RE-5) According to the website, another 3370MW from five different applications are under review by the Oregon Energy Facility Siting Council. That totals 4810MW potential capacity additions. According to the Oregon Office of Energy there are two additional potential projects. PacifiCorp has announced an intent to build a 500MW plant in Klamath County and the Oregon EFSC has received a Notice of Intent for another 500MW plant in Morrow County. Those plants would bring the total of additional capacity under construction or review in Oregon to 5810MW.

In Washington, according to the Washington Energy Facility Siting Evaluation Council web site, four plants totaling 1565MW have already been licensed and slated for construction. Of those, two totaling 1170 MW began construction this year. Another 3160MW from three applications, including SE2, are under review. Two applications for 1570MW are expected by the end of this year. That is a total of 6295MW of potential new generation. (RE-6)

Between the two states there is a total of 12,105MW of new generation already licensed or proposed. That does not include any additional MWs from generation facilities exempt from the respective state siting agency rules. A further indication of the potential new generation in the region comes from the NWPPC. The NWPPC maintains a database of "Generating Project Activity" in the Northwest, including Canada. According to Jeff King, the senior resource analyst who maintains the data, as of September 28, 2001, there are 1070MWs of generation that have completed construction since January 2000. There are 2690MWs of generation that are under construction. Another 9500MWs are in the permitting process. And there are another 6200MWs considered "active" but not in the permitting process. That is a total of 22,410MWs of recently completed or potential new generation in the Northwest. In addition the data shows another 1252MWs of temporarily permitted projects, 1070MWs of which have been completed or are under construction.

The NWPPC March 2000 report found that concerns over insufficiency of supply were primarily short-term over the next few winters. The Council staff used an electricity market model of the Western power system to forecast market-driven resource additions and retirements. Using a commercial electricity market model called AURORA®, the report forecast a net addition of about 9,000 megawatts of capacity for the Pacific Northwest from 1998 through 2017. The model included units that were already completed or under construction at the time, but none of those are included in the Oregon and Washington figures for potential new generation cited above. The model also assumed several older oil-fired gas turbines and a bio-mass unit were retired in the early years. According to the report, those retirements have already occurred. Beginning in 2004, the forecast combined-cycle gas unites would be added at the rate of 500 to 1000 MW a year. The model is very data intensive and the study was careful to point out that because of the large number of assumptions there is an element of uncertainty in the forecast. Nevertheless, Oregon and Washington already have generating units in the current siting process that total over 3000MWs more than the entire net additions forecast in the report between now and 2017. It is clear that the current level of generation either under construction or under review exceeds the amount and the pace at which the Council report forecast new generation would be added through the entire 1998 to 2017 period.

Q. In your opinion, will all this new generation actually get built?

A. As pointed out by Mr. Litchfield, it is hard to predict how much of the proposed generation currently under review will actually become operational. A facility must not only obtain a license but it must also decide that the economics of the business warrant proceeding with construction. That decision will be based on expectations of the market and the ability to recover costs. Construction of a facility may be delayed for several years or it might not occur at all. However, just as one cannot assume that all those that are proposed will be built, one should not assume that the region cannot do without a proposed plant either.

Q. What are the implications of all the new generation activity for the Sumas Energy 2 application?

A. The applicant's case is based on forecasts of the need for new generation and on the events of the past year which it claims demonstrated the dire consequences of inadequate supply therefore justify the need for this particular plant. In the introduction of the June 2001 revised application, after a recitation of past events, the applicant states: "Unless more power generating capacity comes on line in the Pacific Northwest in the near term, wider blackouts, further industry shutdowns, continued high prices and the resulting toll on the regional economy are inevitable." Again after a recitation of past events, Mr. Litchfield further argues in his testimony that the region is better off with SE2 than it is without it because the more supply the better, especially if the developer takes the risks.

However, as the Council pointed out in its order recommending denial, this is an issue of weighing benefits against costs and impacts, one must consider the overall consequences of the plant and determine whether or not the costs and impacts justify granting the license. It is a license not purely for supply, but for supply of particular type at a specific location.

The amount of generation being proposed in the region is substantial and exceeds the forecasts of the NWPPC study. If there is a need for new generation and one plant, for some reason, does not get approval, others may propose another plant at another, perhaps more suitable location. The fact a facility provides additional supply should not, by itself be sufficient justification. Absence of the SE2 facility will not plunge the region into a repeat of the events of the past year.

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Q. The revised application contains a commitment that construction will not begin until SE2 has entered into long term contracts of at least five-years in length for the sale of sixty percent of the facility's output. Does this guarantee the direct benefits to the ratepayers or citizens of Washington State the Council says it is seeking?

A. No, it does not really guarantee any benefits beyond what had been previously espoused and rejected by the Council. It is possible that a Washington retail load serving entity will be one of the purchasers of long-term contracts and the ratepayers will receive benefits from the supply. However, it is also possible that no Washington utility will take the risk of a contract for five or more years or that it will be outbid for such contracts by utilities or marketers outside the state or region. It is possible that increased supply of energy and capacity from SE2 in the Western marketplace will have a downward impact on prices and reduce the threat of outages. But, the Council has already considered and rejected that argument in Order #754 dated February 16, 2001

The Council concluded that the Applicant offered no specific assurances that the benefits will in fact occur. It went on to conclude that, even though the Applicant had shown that the proposed plant would mitigate to some extent forecast energy and capacity constraints and contribute to reliability in the Western states power grid, "…the Applicant has not shown that construction and operation of the plant will confer direct benefits on any identifiable segment of that market (for example, the citizens of Washington State) or lead to lower energy costs in the state or regionally." (Order #754 at 16)

Therefore, f the goal is direct benefits to Washington State beyond the benefits of added energy and capacity to the Western grid, then the commitment to not begin construction until 60 percent of the plant output is contracted for at least five years does not meet that goal. Mr. Litchfield acknowledged this in his first round of testimony when he pointed out that a long-term power contract requirement would not "preserve" the benefits of the power for Washington customers because: “Any entity purchasing the power from SUMAS 11 is likely to be a wholesale entity with the capability to resell the power in the competitive market.” (Exhibit 156 at 12)

In making an offer for five-year contracts at a particular price, SE2 is assessing the current and future market conditions and determining that it is worth the risk of selling a committed supply at that price. The buyer is doing the same thing. The buyer is assessing the current and future markets and their own supply needs and determining that it is worth the risk of assuring a long-term supply at that price. All the commitment means is that SE2, as a seller, has found enough buyers who have concluded that the price offered for the long-term contracts is worth the risk. If they cannot, then the plant won’t be built. If they can, the plant may be built. Since the plant will not be constructed until that threshold has been reached, SE2 is actually reducing its own risk. It has a greater assurance of cost recovery because of the long-term contracts. It is highly likely that any generating unit would not proceed with obtaining financing and beginning construction until it has a substantial amount of potential supply committed to long-term contracts. Given what the Council decided in its previous denial recommendation, all the commitment does is put in place a threshold for construction that any generating company or those who finance it, may very well use as a prudent financial threshold before going ahead on its own anyway.

Q. Do you have any suggestions on additional conditions that can increase the likelihood of direct benefits to the ratepayers and citizens of Washington?

A. If the objective is to assure direct benefits to Washington beyond general energy and capacity benefits to the western grid, and if there is no requirement that any or all of the five year contracts be with Washington load serving entities, then there are a couple of conditions that might be considered. Both are modeled after recent federal decisions and requirements related to the California market. And both have complications in attempting to apply them to one plant in

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Washington. However, the principles involved in both could be adapted and modified for the purpose of helping assure the direct benefits the Council seeks.

Q. What is the first option?

A. One option is to include a "must offer" condition in which the plant is required to offer into the regional spot market any output that is not already scheduled for use. A must-offer condition is currently part of the Federal Energy Regulatory Commission price mitigation strategy in the California ISO and the rest of the Western markets. The must-offer obligation is being imposed by FERC for the expressed purpose of ensuring that all available capacity is in the market and is not being withheld. "A generator that has available energy in real time should be willing to sell that energy at a price that covers its marginal costs, since it has no purchaser at that time," FERC said in its June 19, 2001 order extending the California price mitigation plan for spot markets to all hours and all states. While the FERC order is in effect, any current operating plant is affected by this condition. However, the price mitigation order expires September 30, 2002 before SE2 would be operational. Requiring the plant to offer available power into the regional spot market at all hours would assure that available supply from SE2 will not be withheld and that it will contribute to mitigating supply constraints and resulting price impacts.

Q. What are the complications of this option?

A. The FERC mitigation applies to all generators, except hydro, in the Western market and is in combination with price caps it has imposed. Without the FERC order, the Council would be requiring the condition on only one plant (unless it considers this condition for all future Site Certification Agreements under its jurisdiction). The must-offer conditions also works best in conjunction with price caps. It is not clear whether price caps will be extended by the FERC after the June 19, 2001, order expires. Without a price cap in place, even if a plant must-offer supply,

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there is nothing to keep the plant from offering power at exorbitant prices that would discourage any purchase. This could leave it with power it could sell at much higher prices during the hours when there are more severe deficiencies and the buyers have little discretion about the price. This would in effect be a withholding to secure higher prices later. Furthermore, any plant needs to shutdown from time to time for maintenance and a plant cannot always run at full output.

Q. Would you please then summarize how this recommendation could be structured to avoid these problems?

A. The Council could adopt the condition for all future Site Certification Agreements under its jurisdiction, at least until it is convinced that the developing competitive markets are working as intended. The imposition of the requirement could be conditioned on the amount of the five-year contracts that go directly to Washington load serving entities. It would not apply if a satisfactory amount of supply were contractually committed within the state. A plant specific index to the spot market for the must-offer bid price could be developed and agreed upon. The plant operator could submit a general maintenance plan and schedule, provide notice of any changes in the plan and then accept the burden of proof when it did not offer supply at a time when it deviated from that schedule.

Q. What is the other option the Council should consider?

A. Another option for consideration is requiring the plant to make power available to any control area in Washington State when that control area determines it has been unable to acquire adequate supplies in the market it will have an inadequate supply to meet demand.

Q. What is a control area?

A. A control area is the part of a power system or systems to which a common generation control scheme is applied to match generation and load. The control area operator monitors and regulates the power systems within the control area to match generation with load and to respond to any faults in the system. There are ten control area operators in Washington. BPA has one in Vancouver, and each of the investor owned utilities (PacifiCorp, Puget and Avista), as well as Seattle City Light, Tacoma Power, Grant, Douglas and Chelan have a control center. BC Hydro also has a control area that covers part of Washington.

Q. How would this work?

A. The control area would have to notify the plant that it expects to find itself with an inadequate supply of electricity to meet demand and the plant would have a specified amount of time in which it had to supply the power if it was available. In effect, this condition gives a Washington control area first priority on SE2 supply when there are supply deficiencies that threaten blackouts.

This is similar to a condition that was placed on generators in the West by the Secretary of Energy in an order invoking emergency powers last December to assure electricity supply to California. In that order, the Secretary declared an emergency required entities that had been supplying power to California to sell into the California market if the California ISO certified with the Department of Energy that it had been unable to acquire supply in the market and that it reasonably anticipated an inadequate fuel or energy supply. The California ISO had to notify each entity subject to the order the amount and type of energy or services requested by 6 p.m. PST, the day before the requested service. The entities covered by the order were only required to sell electricity to the ISO that was available in excess of what was needed by each entity to serve its firm customers. The entities covered by the order were initially not required to deliver the energy or services until 12 hours after the filing of the certification. The order was extended twice and was in effect from December 14, 2000, until January 6, 2001. (RE-7) The 12-hour time period was reduced to 9 hours in the first extension order. If one control area is in an emergency situation it means supply in the region is tight and it is likely that other utilities or

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control areas are seeking supplies inn the real-time spot market as well. A requirement that Washington control areas in emergency have first claim on SE2 power would assure that the power would not go outside Washington when a Washington utility is facing a supply emergency.

Q. Are there any obstacles to implementing this option?

A. Yes, there are some difficulties in transferring this concept to SE2. In the case of the DOE order, the terms of any arrangement were to be negotiated by the parties. If they could not agree the Secretary of Energy would prescribe the conditions and then refer the rate issue to FERC for a later determination. A mechanism in Washington would have to be developed to resolve disputed issues over term and conditions in the case where the control area and SE2 could not agree. This might be accomplished by agreeing on an index to the market as a proxy price if the parties cannot reach an agreement. It is also possible that more than one control area in Washington could be in an emergency situation. In the California case there was one control area, hence one buyer, the ISO, and multiple sellers. The ISO was required by the order to allocate its requests for power in proportion to each seller's available excess power. If this condition was applied to SE2, the situation is reversed. There is one seller that could be facing multiple requests from control areas in Washington. Policies would need to be developed to determine whether there should be a proportional allocation of available supply or whether supply would be provided in priority order based on time of the request. The DOE order was not applied during a time in which the FERC must-offer requirement was in effect. The relationship of the must-provide provisions of this condition with the must-offer condition will need to be clarified if both are applied. If adopted, this condition would also work best and be more equitable, applied to other new facilities as well, unless different circumstances warranted otherwise.

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Q. Do the difficulties you've raised with the options for additional conditions mean they should not be adopted?

A. No. The first question that should be answered is whether or not they are appropriate conditions to provide greater assurance of direct benefits from the SE2 plant to Washington. The ability to enhance reliability and avoid an impending outage due to shortfall of supply is a direct benefit to Washington customers, as is assuring that power from SE2 will not be withheld from the spot market in the region. There will be time between the granting of any certificate and the beginning of construction. That time can be used for the affected parties to develop the appropriate policies and agreements necessary to apply the conditions to the specific situation in Washington. Assuming the commitment to long-term contracts was accepted as a condition of the application, the applicant would already have to come back to the Council to demonstrate compliance. The Council could easily also require the applicant to present a methodology for applying and administering the above-suggested additional conditions.

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END OF TESTIMONY

I declare under penalty of perjury that the above testimony is true and correct to the best of my knowledge.

DATED this _____ day of ____________________ 2001.

By___________________________
RONALD EACHUS

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